Time-of-Use Electricity Pricing and Residential Low-carbon Energy Technology Adoption

Jing Liang,[a] Pengfei Liu,[b] Yueming Qiu,[c] Yi David Wang,[d] and Bo Xing[e]

Despite of various types of costly policy instruments such as tax credits and direct rebates, the penetration of energy efficiency and solar energy is still relatively low. Many organizational, behavioral, and market factors have been analyzed in existing literature to explain the low adoption level. Yet, the impact of one particular factor (electricity rate structure) on energy efficiency investment and solar panel adoption is often overlooked in empirical studies. In this paper, we show empirically that consumers facing Time-of-use pricing (TOU) are positively correlated with the adoption of solar energy, compared to consumers on non-dynamic pricing plans.

TOU, one of the most widely adopted dynamic pricing programs, charges different electricity prices depending on the time of the day, i.e. higher prices during peak hours (e.g. late afternoon in summer months) and lower prices during non-peak hours. We compare adoption decisions in energy efficient appliances and solar panels between consumers on non-dynamic rates (marginal electricity prices are constant throughout the day) and those on TOU rates. We use household-level data in Phoenix, Arizona from an appliance saturation survey of 16,035 customers conducted by a major electric utility in 2014 for empirical verification. Probit model and statistical matching methods are employed, and robustness checks are conducted using multinomial logit model, bi-variate probit model, and machine learning matching method.

Our empirical evidence suggests that TOU consumers are associated with 27% higher likelihood to install solar panels, but not more likely to adopt energy efficient AC. Our results have important implications for policy makers to promote the adoption of solar panels and TOU pricing. Our finding of the correlation between TOU and solar adoption suggests that TOU is associated with the same magnitude of impact as financial instruments such as rebates or tax credits of \$2,070~\$10,472, about 85% of current size of financial incentives for solar panels. The result that TOU is positively correlated with solar panel adoption implies that utilities could provide more information for their customers regarding the benefit of TOU for solar adopters. When government or utilities implement educational or informational programs to electric customers, they could bundle the information about the benefits from both solar and TOU, which potentially increases the adoption of both TOU and solar panels. From the cost-effectiveness perspective, combining TOU and solar in policy programs can also achieve a lower cost per additional adoption of TOU and solar.

a Co-first author. School of Public Policy, University of Maryland College Park, USA

b Co-first author. Department of Environmental and Natural Resource Economics, University of Rhode Island, USA

c Co-first author and corresponding author. School of Public Policy, University of Maryland College Park, 3135 Van Munching Hall, College Park, MD, 20742, USA. yqiu16@umd.edu 301-405-8130

d University of International Business and Economics, School of Banking and Finance, China

e Department of Forecasting, Research &Economic Development, Salt River Project, USA

Relative Effectiveness of Energy Efficiency Programs versus Market Based Climate Policies in the Chemical Industry

Gale A. Boyd[a] and Jonathan M. Lee[b]

Industry is one of the largest and most complex energy using sectors of the economy, both in the U.S. and globally, with commensurate level of greenhouse gas emissions. Its complexity makes this sector one of the most difficult to analyze, vis-à-vis climate policy. Engineering analysis of specific industrial processes exist, but empirical economic analysis is largely based on econometrics using aggregate, cross sectional datasets. This paper employs a detailed, non-public, plant-level dataset with a high degree of industry sector disaggregation to simultaneously estimate energy price responsiveness and efficiency, while accounting for heterogeneity, i.e. differences between plants in the chemicals sector. Since regulations or voluntary programs that target inefficiencies are often seen as policy alternatives to market based incentives (e.g. cap and trade or carbon taxes) the paper poses a simple question; *"What level of carbon tax would be required to eliminate the estimated industry level energy efficiency gap?"*

The paper employs stochastic frontier analysis (SFA) of an energy demand equation for electricity and fossil fuel use in four energy intensive sectors; Inorganic Chemicals, Organic Chemicals, Plastics and Resins, and Fertilizers. This sectoral disaggregation is important since chemical industry processes vary widely in energy use. The use of non-public data from the U.S. Census Bureau provides the most detailed source of industry-wide energy and production available. The SFA approach allows the analysis to jointly estimate energy price elasticities and the distribution of energy efficiency. The analysis tests for endogeneity of plant level energy prices, but finds this to be of no concern.

The study finds that few plants achieve anywhere near to 100% efficiency, so that the mean levels of efficiency are not a good estimate of the efficiency gap. When the efficiency gap is based on the 90th percentile of the estimated efficiency distribution the gap is rather small, ranging from 4-9%. Price elasticities range from -0.7 to -1.2. The equivalent carbon price that would close the efficiency gap ranges from \$2.93 and \$152.17 (U.S.) with a weighted average of \$36.61, which is in the range of cost of carbon estimates and current global permit markets. This suggest that a carbon price might be a relatively effective climate policy approach for these industries. Future analysis could expand this approach to other sectors.

a Associate Research Professor. Social Science Research Institute, Duke University, Box 90989, Durham NC 27708; GALE.BOYD@DUKE.EDU

b Associate Professor, Department of Economics, East Carolina University, Greenville, NC 27858: LEEJO@ECU.EDU

Do Energy Prices Drive Outward FDI? Evidence from a Sample of Listed Firms

Grégoire Garsous,[a] Tomasz Kozluk,[b] and Dennis Dlugosch[c]

Business associations and business leaders tend consider cheap energy as vital for manufacturing industries to compete on global markets. High energy prices would arguably reduce industrial output and significantly reduce employment. Consequently, such groups argue that the introduction of a (unilateral) carbon tax would have adverse effects on manufacturing industry activity.

In this paper, we shed light on these claims by estimating the effect of energy prices on firm-level outward FDI. Our estimations are based on an instrumental variable strategy that removes endogenous firms' choices of fuel substitution from observed energy prices. We use a sample of listed firms from 9 manufacturing sectors in 24 OECD countries over the period 1995-2008.

Rults suggest that only relative energy prices—i.e. the difference between domestic energy prices and prices in the FDI destination—rather than absolute energy prices are significantly correlated with firm level FDI. Second, we also find that firms heterogeneously respond to variations in energy prices. Only firms that faced increases in relative energy prices increased their international assets as opposed to those that experienced a decrease in relative energy prices, which did not respond to it. Considering only firms that experienced an increase in (relative) energy prices, we find that, on average, a 1% increase in energy prices is associated with an increase of 0.71 percent in firms' international assets.

Compared to total assets, this increase appears to be small in magnitude. Further results suggest that a 1% increase in relative energy prices is associated with a 0.54 percent increase in firms' international-to-total-assets ratio on average.

Wind Turbine Shutdowns and Upgrades in Denmark: Timing Decisions and the Impact of Government Policy

Jonathan A. Cook[d] and C.-Y. Cynthia Lin Lawell[e]

Due to concerns about climate change, local air pollution, fossil fuel price volatility, energy security, and possible fossil fuel scarcity, governments at many levels around the world have begun implementing policies aimed at increasing the production share of renewables in the electricity sector. These support policies have taken several different forms (e.g., Renewable Portfolio Standards, feed-in-tariffs, tax credits, etc.), and proponents argue that they are necessary for these nascent industries to continue to develop technological improvements, achieve economies of scale, and compete with existing industries. Wind energy was one of the earliest renewable generation

a Corresponding author: Organisation for Economic Co-operation and Development, Economics Department, 2 Rue André Pascal 75775 Paris CEDEX 16 France. gregoire.garsous@oecd.org.

b Organisation for Economic Co-operation and Development, Economics Department

c Organisation for Economic Co-operation and Development, Economics Department

d Salt River Project, Phoenix, AZ; cooks333@gmail.com

e Corresponding author. Dyson School of Applied Economics and Management, Cornell University, 407 Warren Hall, Ithaca, NY 14853-4203; clinlawell@cornell.edu

technologies to be promoted, and its maturity and low costs relative to other renewables has made it a leading option for many countries in the early phases of pursuing climate goals.

For policymakers, an important long-run question related to the development of renewable industries is how government policies affect decisions regarding the scrapping or upgrading of existing assets. How much of the shutdowns and upgrades can be attributed to the policies as opposed to technological progress? How do policies affect the timing of owner decisions and the subsequent path of the industry?

This paper aims to shed some light on these questions by developing a dynamic structural econometric model of wind turbine shutdowns and upgrades in the context of Denmark and using it to estimate the underlying profit structure for turbine owners. In particular, we model wind turbine owners' decisions about whether and when to add new turbines to a pre-existing stock, scrap an existing turbine, or replace old turbines with newer versions (i.e., upgrade). Shutting down and/or upgrading existing productive assets are important economic decisions for the owners of those assets and are also the fundamental decisions that underlie the development of new, growing industries.

The "bottom-up" style of modeling we use in this paper is in direct contrast to many previous "top-down" approaches to examining trends in the wind industry, and the structural nature of our model gives insights into key economic and behavioral parameters. Understanding the factors that influence individual decisions to invest in wind energy and how different policies can affect the timing of these decisions is important for policies both in countries that already have mature wind industries, as well as in regions of the world that are earlier in the process of increasing renewable electricity generation (e.g. most of the U.S.).

We apply our dynamic structural econometric model to owner-level panel data for Denmark over the period 1980-2011 to estimate the underlying profit structure for small wind producers (who constitute the vast majority of turbine owners in the Danish wind industry during this time period), and evaluate the impact of technology and government policy on wind industry development. Our structural econometric model explicitly takes into account the dynamics and interdependence of shutdown and upgrade decisions, and generates parameter estimates with direct economic interpretations.

Results from our dynamic structural econometric model indicate that the growth and development of the Danish wind industry were driven primarily by government policies as opposed to technological improvements. We use the parameter estimates to simulate counterfactual policy scenarios in order to analyze the relative effectiveness and cost-effectiveness of the Danish feed-in-tariff and replacement certificate programs. Results show that both of these policies significantly impacted the timing of shutdown and upgrade decisions made by small wind producers and accelerated the development of the wind industry in Denmark. We also find that when compared with the feed-in-tariff; a declining feed-in-tariff; and the replacement certificate program and the feed-in-tariff combined, the replacement certificate program was the most cost-effective policy both for increasing payoffs of small wind producers and also for decreasing carbon emissions.

Avoiding Pitfalls in China's Electricity Sector Reforms

Michael Davidson[a] and Ignacio Pérez-Arriaga[b]

Previous literature has documented how restructuring an electricity sector is difficult, can require years of detailed planning, and may ultimately fall short of creating efficient institutions. China has recently reinvigorated its three-decade-old process of electricity market reforms, which has the potential to increase efficiency in a sector where central and local governments have historically had large planning roles. However, several warning signs—"pitfalls"—that the current round may fail to achieve its broader aims remain.

Based on well-established regulatory economics literature and international lessons, we identify five pitfalls to avoid: (i) physical contracts rather than more flexible financial contracts, (ii) forward or specialized markets prior to a standard spot market, (iii) retail competition prior to an efficient wholesale market, (iv) inadequate attention to conflicts of interest in system operation, and (v) insufficient commitment to a strong, independent regulator. Many details and initiatives are left to provincial governments, which we explore through a careful review of the available literature on China's market reforms and reform experiences globally; market design and market outcome documents of Chinese experiments (where available); and a large number of interviews mostly in Mandarin Chinese with stakeholders in government agencies, regulators, grids, generation companies, and research organizations.

We find that ongoing changes to contract structure, system operation, and regulatory independence are likely to achieve some efficiency gains with respect to the planned system, but fall short of what is possible, including incentivizing system flexibility given increasing renewable energy penetrations. Several underspecified elements of central guidelines—such as scheduling—have not been sufficiently reformed in provincial pilots.

Three possible reform pathways emerge from this analysis: a continuation of current efforts leading to stalled markets with enhanced administrative and idiosyncratic measures; a move toward self-scheduling with liquid secondary markets; or strengthened centralized scheduling with large financialization of forward contracts. Implications for China's reform policy include the likely need to strengthen the central regulatory bureaucracy and standardize market designs to facilitate inter-provincial coordination. A consistent policy on transition mechanisms could help bring along ambivalent or oppositional local governments. The difficulties for China to improve efficiency and flexibility are also replicated in other emerging markets, such as India, indicating future research directions into how standard liberalization models are implemented in diverse contexts.

a Corresponding author: School of Global Policy and Strategy, University of California San Diego. Mechanical and Aerospace Engineering Department, University of California San Diego, La Jolla, CA 92093. Email: mrdavidson@ucsd.edu

b Center for Energy and Environmental Policy Research (CEEPR), Sloan School of Management, Massachusetts Institute of Technology, Cambridge, MA 02139

Disentangling Costs of Persistent and Transient Technical Inefficiency and Input Misallocation: The Case of Norwegian Electricity Distribution Firms

Subal C. Kumbhakar,[a,b] Ørjan Mydland,[b] Andrew Musau,[b] and Gudbrand Lien[b,a]

Numerous studies have focused on estimating technical inefficiency in electricity distribution firms, although only a handful distinguish between its persistent and transient cost inefficiency components. Furthermore, almost none of the studies estimated the cost of input misallocation arising from non-optimal use of inputs that results from failure to minimize costs exactly because of some institutional, structural, and managerial problems. The cost function (input distance function) used in the stochastic frontier literature to model inefficiency does not allow for the separation of technical inefficiency and allocative inefficiency. It is subsequently not clear whether inefficiency derived from estimating the cost function represents the sum of costs of technical and allocative inefficiency. Stated differently, what is uncertain is whether overall cost inefficiency can be estimated in a stochastic frontier framework under the assumption that the sum follows a half-normal (or truncated normal) distribution. More likely, focusing on the estimation of technical efficiency while ignoring allocative efficiency will result in wrong parameter estimates and incorrect estimates of the cost of technical inefficiency.

In this paper, we estimate both persistent and transient components of technical inefficiency and input misallocation using Norwegian panel data for 146 electricity distribution firms observed over the years 2000 to 2016. Our modeling and estimation strategy is to use a system approach, consisting of the production function and the first-order conditions of cost minimization. Input misallocation for each pair of inputs is modeled via the first-order conditions of cost minimization. We also estimate the costs of technical inefficiency and input misallocation by deriving the cost function for a multi-output separable production technology. Our modeling and estimation strategy handles endogeneity of inputs and allows for inclusion of determinants of both persistent and transient technical inefficiency while controlling for firm-effects.

Input variables in our study include capital, labor and operational costs, whereas output variables are total number of customers and size of network, defined as the length of high-voltage power lines in kilometers. We find evidence of input misallocation, viz., excessive use of labor relative to capital and excessive use of materials (operational costs) relative to capital. The estimated cost of input misallocation for the electricity distribution firms ranges from 9.4% to 10.9% across different model specifications. We find the presence of persistent technical inefficiency, with overall technical inefficiency accounting for between 6.8% and 24.3% of the distribution firms' costs.

Our results call into question a commonly imposed modeling assumption that all firms are fully allocatively efficient. From a regulatory point of view, it is therefore imperative that the cost of input misallocation be explicitly considered in the benchmarking, in addition to the costs arising from technical inefficiency. Furthermore, identifying systematic shortfalls in managerial capabilities that generate persistent inefficiency and distinguishing these from non-systematic management problems in the short run is necessary, especially in setting optimal efficiency targets.

[a] Department of Economics, State University of New York, Binghamton, NY13902-6000, USA

[b] Inland School of Business and Social Sciences, Inland Norway University of Applied Sciences, P.O. Box 952, NO-2604 Lillehammer, Norway

Corresponding author: E-mail: Gudbrand.Lien@inn.no.

Intra-day Electricity Demand and Temperature

James McCulloch[a] *and Katja Ignatieva*[b]

We aim to explain the relationship between high frequency electricity demand, intra-day temperature variation and time.

Using the Generalised Additive Model (GAM) framework we link high frequency (5-minute) aggregate electricity demand in Australia to the time of the day, time of the year and intra-day temperature. Using yearly and seasonal demand models, we document a strong relationship between high frequency electricity demand and intra-day temperature.

We establish a link between electricity demand and human activity cycle (modelled through the time of the day), and show that using Daylight Saving Time (DST) as an independent variable for the time indexed daily periodic demand consumption function provides an improvement of fit compared to using standard (astronomical) time. We introduce the time weighted temperature model that captures instantaneous electricity demand sensitivity to temperature as a function of the human daily activity cycle, by assigning different temperature signal weighting based on the DST time. The major novel result of this paper is that the temperature demand signal is time weighted. This relates the magnitude of the temperature demand signal to the daily activity cycle based on DST.

Our single temperature parsimonious GAM model is accurate with a next day demand forecast MAPE (Mean Average Predicted Error) of 3.2%. The parsimonious GAM model, thus, provides a solid foundation for the development of more elaborate multivariate models for forecasting high frequency electricity demand.

Global Climate Change Mitigation: Strategic Incentives

Sigit Perdana[c] *and Rod Tyers*[d]

Constraints facing the success of the Paris Accord arise from the costs of mitigation actions and incentives for regions to free ride. In this study the effects of varying numbers and sizes of regions that might commit to pricing carbon emissions are considered by conducting simulations of a global economic model and combining these with the results from a meta-study of the temperature and economic welfare impacts of alternative levels of global carbon emission. Three IPCC temperature rise cases are considered: "low", "best" and "high". In the "best" case, the results suggest that the absence of further carbon mitigation will see the average surface temperature rise by four degrees Celsius by 2050, bringing with it a loss to the global economy of 15 per cent of its GDP. In the IPCC "high" temperature case this impact is almost doubled. More modest results emerge in the "low" temperature case.

Mitigation simulations indicate, first, that the more widespread is its implementation the more the already energy-efficient regions, including the EU and Japan, enjoy net gains not only from lower temperatures but also from competitiveness. Second, in the "best" and "high" IPCC tempera-

a Corresponding author. Kellerberrin, Australia. Email: james.duncan.mcculloch@gmail.com

b Corresponding author. UNSW Australia, Business School, School of Risk and Actuarial Studies, Sydney, NSW 2052, Australia. Email: k.ignatieva@unsw.edu.au

c Corresponding author: Department of Economics, Business School University of Western Australia, Perth WA 6009, E-mail: sigit.perdana@uwa.edu.au.

d Business School, University of Western Australia and Research School of Economics, Australian National University.

ture scenarios, the US and China would derive positive net economic gains from unilaterally pricing carbon, irrespective of the behaviour of other regions. In the "best" scenario this extends also to the EU. We then examine whether implementation by the remaining regions would further benefit these large emitters, sufficient for them to afford side payments large enough to induce the other regions to do so. We find that, so long as future benefits and costs are discounted at the 2017 ten year Treasury bond yield, the additional gains to the "big three" are more than sufficient to finance such side payments. At higher rates of discount, only the IPCC "high" temperature scenario yields net gains to the big three that are large enough to compensate other regions for participation.

Finally, it is shown that carbon abatement policies will be politically difficult to implement by all countries, even the net gainers from unilateral implementation. This is because mitigation costs begin immediately but offsetting benefits do not dominate for at least two decades. Implementation in the "anchor" regions is therefore unlikely and, since side payments would only add to annual costs in the first two decades, the potential for wider coalition building also looks bleak. Widespread implementation of abatement policies will therefore require strong forward looking behaviour by governments.

Revisiting the Income Elasticity of Energy Consumption: A Heterogeneous, Common Factor, Dynamic OECD & non-OECD Country Panel Analysis

Brantley Liddle[a] and Hillard Huntington[b]

As nations commit to planned reductions in their emissions intensity as part of the Paris Agreement on climate change, understanding the macro energy elasticity of GDP is very useful for both planning and developing policy responses. This analysis contributes to the extensive literature on the relationship between economic development and energy demand by assembling a rich and deep (many years) dataset on energy prices by country. We combine this dataset with a wide panel dataset of energy consumption and economic growth for 37 OECD and 41 non-OECD countries. This panel information allows the research to develop conclusions about not only a number of developing and developed economies but also shifting energy market conditions over nearly six decades. Controlling for energy price conditions experienced in each country over multiple years provides an opportunity to estimate the relationship between energy use and economic development more precisely than has been previously available.

The researchers spend considerable effort in estimating aggregate energy demand responses that are dynamically consistent. Their techniques adjust for the possibility of that the observed energy and economic data points have means, variances and covariances that change over time (a problem called nonstationarity). Additional steps allow the price and income responses to vary by country (a characteristic called heterogeneity). Further procedures are adopted to control for the possibility of common global or temporal shocks (a feature termed as cross-sectional dependence).

Most results in this analysis suggest that the GDP elasticity is less than unity (e.g., 0.7)—i.e., energy intensity will fall with economic growth. Most evidence suggests that the GDP elasticity is similar for OECD and non-OECD countries, and for non-OECD countries, similar across income-bands. Also, there is no evidence that individual country elasticity estimates (for GDP or

a Corresponding author. Energy Studies Institute, National University Singapore. E-mail: btliddle@alum.mit.edu.
b Energy Modeling Forum, Stanford University. E-mail: hillh@stanford.edu.

prices) vary systematically according to income. The price elasticity is larger (in absolute terms) for OECD than for non-OECD countries—indeed, it is typically insignificant for non-OECD countries.

The Vertical and Horizontal Distributive Effects of Energy Taxes: A Case Study of a French Policy

Thomas Douenne[a]

In 2014, France has introduced a carbon tax on energies called "Contribution Climat-Energie". The tax has reached 44.6€/tCO2 in 2018 and was supposed to continue growing to reach 86,2€/tCO2 by 2022. Yet, following the protests of the "Yellow vests" against the impact of energy taxes on households' purchasing power, the tax has been frozen at its 2018 level. This event stresses that distributive effects may strongly dampen the acceptance of energy taxes. It therefore raises the necessity to assess their actual distributive effects and to look for solutions to alleviate them.

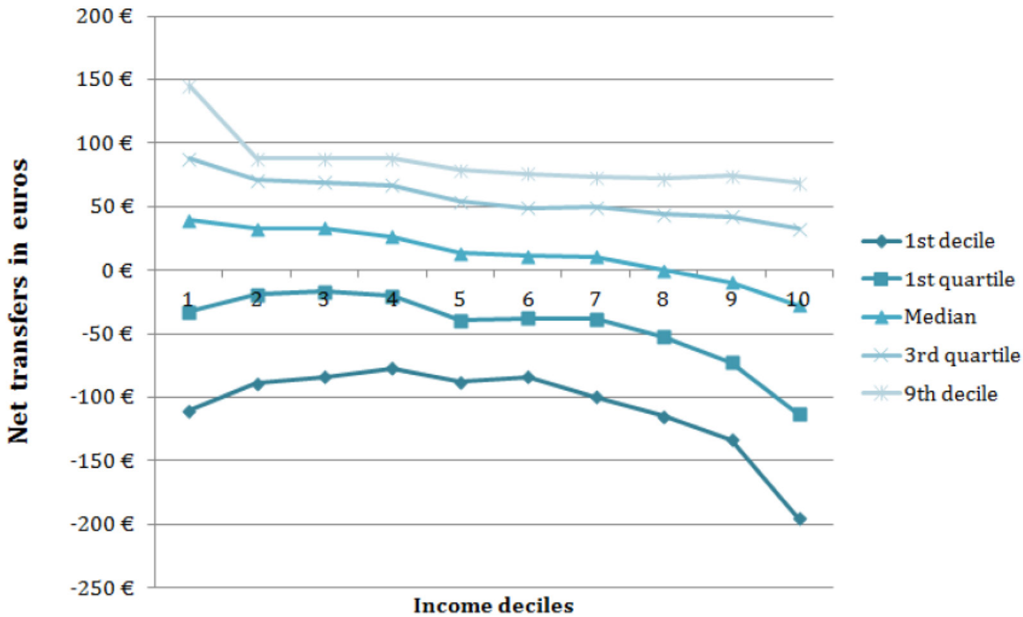
To do so, this paper evaluates the distributive effects of the increase in French energy taxes conducted between 2016 and 2018. From households' survey data, I use microsimulation to compute the incidence of these taxes at the household level. In order not to over-estimate the tax burden, the model accounts for responses to prices through the computation of price elasticities for energies. Households appear to react significantly to variations in transport fuel prices in the short run, and to a lesser extent to variations in housing energy prices, with elasticities of respectively -0.45 and -0.2. Reactions are also estimated to be stronger for poor households or households living in less dense areas.

From the simulation of households' level tax incidence, I first analyze the expected *vertical* distributive effects, i.e. distributive effects between households along the income dimension. I find that the tax is regressive as it represents a higher share of income for poorer households. The increase in taxation from 2016 to 2018 is expected to cost on average 0.6% of the disposable income of a household in the first income decile, against 0.2% for a household in the last income decile. Considering total expenditures instead of disposable income to represent standards of living, the pattern becomes much flatter and for all income groups the increase in tax costs around 0.35% of their budget. The small-scale compensation mechanism proposed by the French government should not change this picture. However, returning the revenue left through neutral lump-sum transfers would make the policy largely progressive: households in the five first income deciles would on average gain from the policy, while the last two deciles would on average lose.

Yet, even in this situation the policy's acceptability could be dampened by *horizontal* distributive effects—i.e. between households with similar incomes – that are in magnitude much larger than vertical ones. Indeed, I find that among each of the three first income deciles, we may expect over 30% of households to lose from the policy, while 40% of the top income decile would win. As shown by the figure below, 25% of households in the first income decile are also expected to lose more than the median household in the top income group. Thus, if one may easily propose a progressive carbon tax by returning the revenue neutrally to all households, such a policy would still generate large horizontal distributive effects and harm an important share of low-income households.

a Paris School of Economics, Université Paris 1 Panthéon-Sorbonne. Phone: +336 1650 7531. E-mail: thomas.douenne@psemail.eu. Postal: 48 Boulevard Jourdan, 75014, Paris, France.

FIGURE – Distribution of households' net transfers per c.u. after flat-recycling, by income decile



To understand the determinants that might explain the large heterogeneity in the tax incidence, I then regress the expected net transfers received by households on many characteristics. At first, we observe that the urban density of the household residence plays a major role, with less urban households losing significantly more from the policy. However, after controlling for other characteristics, this effect appears largely driven by covariates. In particular, the most important factor that comes out is the type of energy used by households. Other variables such as households' composition, age, as well as some physical characteristics of their home are also significant determinants.

Finally, I simulate alternative transfers targeted towards the losers from the policy. I test transfers to low income households differentiated according to the urban density of their residence, on their heating mode, or both. These mechanisms could somewhat lower distributive issues, but their effect remains quite limited.

The results of the paper have important policy implications. First, it shows that a carbon tax is in itself regressive. Second, if the revenue of the tax is returned neutrally to all households, a majority of poor households become net winners, which could potentially increase the tax' acceptance. Third, even in this case the policy would leave a substantial share of poor households worse off. If people value horizontal equity, a progressive tax could thus be rejected based on equity criteria. Fourth, dealing with horizontal heterogeneity is much more difficult. In the short run there seems to be no adequate instrument to tackle these effects. In the longer run, energy efficiency improvements seem necessary to reduce both emissions and distributive effects.

Pathways to 100% Electrification in East Africa by 2030

Giacomo Falchetta,[a] Manfred Hafner,[b] and Simone Tagliapietra[c]

East Africa is endowed with substantial energy resources and has sufficient techno-economic generation potential to guarantee universal and secure energy access in the region. Local potential includes solar photovoltaic and hydropower (both large and small-size) across all countries, geothermal in the Rift Valley countries (between Kenya and Malawi), bioenergy, wind, and hydrocarbon resources (oil in Uganda, natural gas in Mozambique and Tanzania, coal in Mozambique). Nonetheless, the region has an electricity access level of 36%, with over 140 million people without access. The share of regional population without access to electricity has fallen from 90% in 2000 to 64% in 2017, but the absolute number of people without access has instead increased by 8 million as electrification efforts have been outpaced by rapid population growth.

In this paper, spatially-explicit least-cost 100% electrification scenarios by 2030 for East Africa (in compliance with the UN's Sustainable Development Goal 7) are modelled within the OnSSET (Open Source Spatial Electrification Tool), which allows for high-resolution bottom-up assessment of the cheapest technologies in each settlement. We develop higher and lower demand tier scenarios for new electrification. This allows us to differentiate between supply options that are only enough to guarantee basic household electricity for *e.g.* lighting and air circulation purposes, and higher targets guaranteeing a supply level that allows for some productive uses of electric energy, such as agricultural irrigation and crop processing. Parallelly, three regional grid electricity generation mix scenarios are designed, and capacity additions and corresponding investment required to satisfy baseline growth (i.e. from already electrified consumers and other sectors) in the demand for electricity is also estimated.

Results suggest that the total required investment for guaranteeing basic to moderate consumption for new customers by 2030 stands at \$57 and \$110 billion, respectively. This corresponds to an average of \$5.6 billion/year, and overall implies capacity additions of 12.2 GW (with a median optimal mix of 59% of on-grid, 37% of mini-grids and 4% of standalone solutions capacity). Besides new electrification, at least further \$2.7 billion/year of investment in generation capacity are required to satisfy projected demand growth. If such figures are put in perspective and observed in per-capita or as a share of GDP terms (overall \$23 per capita or 2.7% of regional GDP in the first reference year, increasing at a rate consistent with the projected compound annual growth rate of electricity demand), investment requirement figures offer greater room for a policy-oriented interpretation. A further result is that a grid electricity scenario with a higher penetration of renewables at 25% cheaper utility-scale photovoltaic cost reveals to be 4.4% cheaper and 46% less carbon-intensive over the long-run, while also requiring less up-front investment.

To achieve such objectives, the financing challenge is nevertheless considerable. In the discussion section of the paper, we then proceed highlighting diverse policy action required to tackle the very diverse roadblocks currently affecting non-electrified people and already electrified hotspots in East Africa, where demand will growth robustly in the coming decade. Calibrated input data is hosted in an online repository to allow reproduction of results and alteration of parameters under different assumptions, scenarios, and policies.

a Corresponding author. Email address: giacomo.falchetta@feem.it

b Email address: manfred.hafner@feem.it

c Email address: simone.tagliapietra@feem.it